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CHAPTER XIV - COMPARATIVE PERFORMANCE UNDER THE LOANS

I. Introduction

1.01 This review has covered ten companies, to which the Bank has made 39 loans, of which 28 are fully or nearly fully disbursed. The preceding chapters, in Parts II and III, have analyzed performance under the loans company by company and loan by loan. The purpose of this chapter is to draw together the results established and to analyze, in a summary but systematic fashion, the performance of the projects and the companies, mainly with regard to the direct objectives of the Bank loans in terms of schedules, costs and degrees of achievement; therefore, this chapter will deal principally with the 28 loans fully or nearly fully disbursed.

1.02 In broad terms, the Bank's loans have been intended to enable expansion of electricity supply in line with demand. The more specific objectives of the loans can be classified under the following headings:

- (a) size of facilities required to meet the demand for power;
- (b) time schedules and costs of these facilities;
- (c) financing plans for these facilities and overall investment programs;
- (d) operational efficiency of the companies; and
- (e) institutional development and rationalization of the companies and power sector.

Following this small introduction, the present chapter is therefore divided into 5 parts. Section II discusses the crucial load forecasting and investment planning aspects of the decisions and justifications for the various expansion projects partially financed by the loans; it will in particular evaluate the validity of the load forecasts made by or for the Bank and, in a summary fashion, of the planning methods used for determining the amount and the size of the investments. Section III reviews the physical implementation of the projects financed by Bank loans, with regard principally to commissioning dates, construction periods, technical performance and construction costs. Section IV deals comparatively with the effectiveness of Bank loans to the financing of the companies' investment programs. Section V attempts to make, on a comparative basis, an overall evaluation of the companies' performance on operations, costs and management efficiency. Finally, Section VI briefly analyzes the principal topics covered by the covenants attached to the various loans, and performance under them.

II. Load Forecasts and Investment Planning

2.01 As discussed in Chapter I (para. 4.02), the power projects for which the Bank's loans have been made have been justified as investments principally by showing that they would be necessary to enable the power system to meet forecast peak demand in the system's service area. Generally, load growth forecasts have been prepared by the borrowers and/or their consultants and accepted by the Bank's staff, sometimes with minor amendments;[1/] load growth has usually been projected on the basis of past trends or of experience in other countries, sometimes with special

1/ The Bank prepared a revised (lower) forecast of load growth for one of the Colombian projects (EPM - Guatape project); however, it kept to the capacity installation plan recommended by the company's consultants.

adjustments for the backlog of unmet demand (SEGBA, Furnas) or for major industrial loads expected to arise in the future (CFE, VRA, NEB). Capacity installation has generally been planned so as to meet the projected demand at times of system peak (for Furnas, EELPA, and some predominantly hydro systems of CFE and in Colombia, capacity extension was planned also on the basis of energy requirements) plus some simple and generally conservative reserve criterion as insurance against shortage -- e.g. 10 or 15% of demand in large systems with numerous units (Central and Interconnected systems of CFE), use of lowest recorded flow year for hydroelectric systems, or, most of the time, 'largest unit out'. The following Table 14.1 shows the main responsibility for load forecasting and capacity installation planning in connection with the different loans and some of the main characteristics of the planning bases used, varying among companies and projects according to the different characteristics of the various power systems and projects.

2.02 As regards the demand forecasts, which, as pointed out, formed an important part of the basis of the Bank's decision to support the projects, comparisons between forecast and actual demand levels were made in each of the company chapters. For comparative purposes with regard to capacity planning, we adopt a slightly different procedure here, based on a technique developed by Mr. Dennis Anderson of the Bank's Economics Department.[1/] Since the size of investments in capacity expansion is generally settled by the expected increase in peak demand and energy requirements over the base year used for the projection, the accuracy of the fore-

1/ See Economics Department Working Paper No. 79 'Ex-Post Evaluation of Electricity Demand Forecasts' IBRD - June 1970.

casts is defined here by the ratio

$$R = \frac{\text{Forecast Change in Demand from Base Year}}{\text{Actual Change in Demand from Base Year}} \times 100\%$$

The error in the forecast is given by the expression (R - 100)%. The following table shows the main characteristics (mean and standard deviation) of the frequency distribution of the ratio R by forecast intervals (number of years ahead) for the energy sales and the annual peak demands, respectively. Details are given in Appendix Tables 14.1 and 14.2.

TABLE 14.2: MEAN AND STANDARD DEVIATION OF R BY FORECAST INTERVALS FOR ENERGY SALES AND PEAK LOADS

	Forecast Intervals (years ahead)													
	1	2	3	4	5	6	7	8	9	10	11	12	13	Total
Sales														
Observations	28	29	29	28	20	18	12	9	4	3	0	0	0	180
$\overline{R}$ %	86	116	116	117	120	112	115	103	97	99	-	-	-	108
S %	53	39	29	34	33	38	32	34	25	30	-	-	-	38
Peak Load														
Observations	33	34	35	34	31	25	17	14	10	4	1	1	1	240
$\overline{R}$ %	87	109	115	116	112	108	110	122	85	128	198	(200)	180	123
S %	54	53	46	43	46	51	36	42	29	56	-	-	-	50

$\overline{R}$ = Mean of R
S = Standard deviation of R

It should be stressed that the figures presented in Table 14.2 are based on calculations leaving out the extreme observations in which forecasts were 200% or more of actuals. Inclusion of them would make most of the numbers substantially higher, particularly in the case of the peak loads, for which more than 10% of the observations fell in the '200% or above' category; the mean would then be 131 (against 123 shown in Table 14.2) and the standard deviation would be 88 (against 50). Full details on this point are given in the Appendix Tables referred to. It should also be noted that the energy analysis refers to a smaller number of cases than the peak load analysis, due to differences in availability of data, so that the results cannot be understood to reflect the energy and the peak demand facets of a single sample.

2.03 Table 14.2 shows that, omitting the extreme cases, forecasts of increases in energy sales averaged 8% above actual increases over all forecast intervals and had a standard deviation of 38%. Forecasts of increases in peak loads have been relatively more over-optimistic in general and have also shown greater dispersion; forecasts average 23% above actuals and show a standard deviation of 50%.

2.04 The Economics Department Working Paper already mentioned analyzed the performance of the load forecasts accepted by the Bank for 75 loans to companies in 37 different developing countries, a larger sample than covered here which nevertheless included many of the loans we have reviewed. It is interesting therefore to make some comparison of results. The Working Paper concentrated principally on energy forecasts (as opposed to peak demand forecasts) and found results almost identical to ours for the dispersion of the forecasts' accuracy but a significantly lower degree of overestimation on average. Standard errors for the two cases, including and excluding observations above 200%, were 46 and 38 (compared with our 47 and 38). Corresponding mean values of R were 109 and 102, compared with our 118 and 108.

2.05 The Working Paper also analyzed some data gathered by the U.N. Economic Commission for Europe, referring to selected countries in Eastern and Western Europe together with the U.S. These data yielded an R of 102, rather comparable with what had been found for the developing countries to which the Bank had lent, but a standard deviation of only 19, exactly half that found for the developing countries. Our figures confirm the much greater error apparently typical for load forecasts for the developing countries, as contained in Bank project appraisal reports, but also suggest a more systematic tendency to exaggeration in load forecasting.

2.06 Load forecasts for different intervals have different relative importance. From the point of view of the amount that it is decided to invest in capacity the most important forecasts are those for some 3 to 7 years ahead, corresponding approximately to the periods normally required to build different types of generating plant. Shorter forecasts are more important for distribution planning and for financial forecasting, while longer forecasts are more important from the broader system planning point of view and selection of different types of plant, as opposed to different sizes. It is worthwhile therefore to make some more specific comparison between the findings of the Economics Department paper and our own for the period 3 to 7 years ahead.

TABLE 14.3: ACCURACY OF LOAD FORECASTS 3-7 YEARS AHEAD

	Forecast Intervals (years ahead)				
	3	4	5	6	7
A. Energy - Excluding Cases over 200%					
1. Anderson[a/]					
R	114	106	101	102	94
S	30	35	35	39	40
2. Ten Companies[b/]					
R	116	117	120	112	115
S	29	34	33	38	32
B. Energy - Including Cases over 200%					
1. Anderson[a/]					
R	120	117	111	102	94
2. Ten Companies[b/]					
R	120	117	120	117	125

a/ in Economics Department Working Paper No. 79 (June 1970)
b/ Present sample.

The table shows that, for this important period, the sample reviewed in this report again shows considerably larger overestimates of energy sales, on average, than the sample used in the Working Paper. The standard deviations are generally not significantly different.

2.07 Usually more important for investment planning than the energy forecasts are the peak demand forecasts. Table 14.2 showed that, on average, for the samples of different scope covered by the two analyses, peak demand forecasts overestimated the actual more seriously than energy forecasts. On the other hand, in the critical period 3-7 years ahead, it is noteworthy that the average overestimate of peak load (on a percentage basis) is in fact less than the average overestimate of energy sales. This is odd, since the evidence from the Economics Department Working Paper as well as other data available to us, some presented below, in fact suggest that there has been a fairly systematic tendency to underestimate future load factors so that, if energy sales are overestimated then peak loads should be more seriously overestimated. The explanation for these apparently contradictory findings is that the samples covered in the peak load and energy analyses summarized in Table 14.2 are not identical, as mentioned, and that the Mexican cases, where the tendency to underestimate future load factors seems to have been less (and sometimes they have in fact been overestimated), bulk particularly large in the analyses done here and especially in the peak load analysis. Thus, the conclusion to be drawn is that no significance should be attributed to the relationship between the peak load and energy figures shown in Table 14.2, and the energy findings should be considered more generally relevant than those for peak loads.

2.08 The fact that future loads have generally been significantly overestimated, as implied by the figures presented in the preceding pages, raises the question whether overinvestment in generating capacity has resulted. Comparisons have therefore been made between actual and projected levels of gross reserves (defined as the difference between installed capacity and peak load). Though they include all allowances for scheduled and unscheduled outages and for hydrological variability and are somewhat exaggerated insofar as capacity installed at the end of a year is compared with peak demand which occurred during that year, gross reserves were chosen as a simple standard concept applicable to all systems and appropriate for the present analysis. The accuracy of gross reserve forecasts has been measured in a similar manner to that used before -- i.e. by the ratio between forecast and actual -- except that here we deal in absolute levels rather than in terms of changes from a base year. The following table shows indicators of accuracy in the forecast of peak load increase and of reserve capacity as well as average actual gross reserves as a percent of peak load (unweighted).

TABLE 14.4: ACCURACY OF FORECASTS OF PEAK LOADS AND GROSS RESERVES

	Forecast Intervals (years ahead)									
	1	2	3	4	5	6	7	8	9	Total
Peak load accuracy	164	129	141	123	115	112	124	129	99	131
Gross reserve accuracy	118	80	59	112	108	312	122	131	75	115
Actual gross reserve as % of actual peak load	36	35	41	40	37	34	38	34	23	36

The table shows that, even with the shortfalls in peak loads from expected levels, gross reserves have nevertheless usually also turned out less than forecast. However, actual reserve ratios have been by no means low.

2.09 To say whether these apparently high gross reserve ratios really indicate excessive provision of capacity it is necessary to make the analysis much more specific to the case of each company. The most critical question is whether, at the outcome of many years of Bank involvement with each company, there is evidence of excessive capacity for meeting actual peak loads. Therefore, to avoid making the comparative analysis excessively complex, we concentrate principally on the situation obtaining in 1970. Table 14.5 shows that actual gross reserves on the principal systems of each of the ten utilities under review varied in 1970 between 8 and 88 percent of peak loads, averaging 32%. The table also gives forecasts of installed capacity and peak loads for 1970, generally reproduced from the appraisal reports for the most recently completed Bank-supported project for each company.

2.10 More meaningful than gross reserves for indicating system reliability is the concept of spare capacity at the effective peak, effective peak being defined as the critical time in the year when the margin between demand and capacity actually available (after water losses and maintenance outages) is least or load shedding greatest (excluding short-term outages). The concept was applied by computing the average capacity actually available over each month (after allowances for all outages lasting more than 2 days) and comparing this with peak demand on the peak day in the month; the month with the narrowest positive margin or greatest deficit was designated effective peak. This is a rather strict criterion; spare capacity existing at effective peak is clearly useful only as an insurance against the risk of failure, a risk which by definition did not materialize in the year in question.

2.11 Table 14.5 suggests that, as of 1970, there was no evidence of excess capacity on eight of the fourteen systems under study (including five systems of CFE), given the level and the shape of the demands which they confronted. Actual gross reserves were somewhat less than had been forecast for SEGBA, FURNAS, EELPA, VRA, EPM, CVC/CHIDRAL and all the systems of CFE. SEGBA's spare capacity and gross reserves were on the low side, even allowing for the 200 MW capacity available from interconnected companies, although the more serious deficiencies have been on the side of the distribution network (see Chapter II). Somewhat the same regarding spare capacity could be said of Furnas and the systems with which it is interconnected, except that they are definitely in a much stronger and more satisfactory position (Chapter III) than the Buenos Aires network. In Colombia, spare capacity was low in EEEB's system and negative in the case of CVC/CHIDRAL; apparent substantial gross reserves and spare capacity in EPM's system do not take into account the limited availability of hydro energy (Chapter XI). In the Central, North and North East systems of CFE, gross reserves and spare capacity as of 1970 were not excessive.

2.12 Gross reserves amounted to more than 20% of peak load in the Interconnected and North West systems of CFE. However, due to the lack of acceptance testing of units in the past, the effective capacity in the North West system is significantly lower than the installed name plate capacity; moreover, hydrological conditions cause the effective capacity to fluctuate substantially through the year, so that the available capacity (after maintenance outage) provided only small spare capacity at the effective peak in 1970. The lack of data about the effective peak pattern in the large Interconnected system prevents a full judgment, but the amount of gross reserves in 1970 for this system was not excessive. The somewhat satisfactory 1970 situation in CFE's systems, due principally to a boost in 1970 demand significantly above the levels forecast (except in the North West system), followed several years of the mid-1960's during which there was significant excess capacity in several CFE systems (Central, Oriental, North and North East), as discussed in Chapter VII. Reserves and spare capacity on the VRA system indicate some evidence of excess capacity, but slightly less than expected; however, such large amounts of reserves as had been allowed for in forecasts have been required due to the large size of units and to the special nature of the power contract with the principal consumer and the nature of its aluminum smelter load (see Chapter V).

2.13 Reserves on the small Ethiopian interconnected system were very large in percentage terms, due partly to the large size of units relative to the small load; though installed capacity includes substantial amounts which may be unavailable in poor hydrological years (about 25 MW out of 94 MW), the lowest available capacity in 1970 was 67 MW, leaving a spare capacity of 22 MW equivalent to 49% of the demand at the effective peak; this evidence of overinvestment, though not conclusive, is further strengthened by the fact that in February 1971 an additional 32 MW were commissioned, so that the system presently has about 100 MW of firm capacity for a peak load slightly above 50 MW and growing at about 10% per annum.

2.14 The other systems which show evidence of overinvestment in generating capacity, at least relative to the other systems studied, are the main interconnected network of NEB (Malaysia) and the Singapore system (PUB). The former is predominantly thermal and the latter entirely thermal. The 1970 peak load on the NEB interconnected system reached exactly the level forecast; the 1970 peak load on the Singapore system fell substantially short of expectations -- by more than 60 MW or nearly 15% of the forecast level -- entirely due to a serious underestimate of the load factor, since actual energy sales and their composition were extremely close to the levels forecast. Overestimate of demand is therefore a large part of the reason for the seemingly excessively high spare capacity at effective peak on the Singapore system in 1970. But there has also possibly been too large an allowance in PUB's planning (despite the problems experienced, as described in Chapter VIII) for maintenance outages, and this may apply more strongly to the NEB system, which has shown very substantial effective reserves in the last two years despite the relative accuracy of the load forecast. It would seem that more attention should have been given in these two systems both to load growth composition and load factor trends, and also to the possible advantage of using, with the assistance of the consultants, stochastic concepts and methods for quantifying the probability distribution of failure of each generating unit and for setting an optimal balance between the risks of falling short of the demand and the amount of investment in generating capacity. Deeper investigation of planning methods actually in use, trends over periods of years, fuel- and capital-cost savings of larger-size units, determinants of load growth, actual outage experience, etc., would be needed to determine definitively whether these are the measures which would be appropriate, but it seems decidedly doubtful whether it has been worthwhile to install as much capacity as has actually been added in these two systems.

III. Project Costs and Construction Schedules

3.01 Out of the 39 loans under review, the 28 which have been fully or nearly fully disbursed have helped to finance completed projects with a total cost of about $2,874 million equivalent, of which $1,666 million for generation, $562 million for transmission, and about $564 million for distribution; rural electrification projects partly financed by the Bank in Ethiopia and Mexico have a total cost of $81 million. This composition reflects the traditional emphasis in Bank lending upon generation.

3.02 As mentioned in para. 2.08, despite the general overestimation of the peak load in forecasts, gross reserves have tended, on average and for most years, to be lower than projected. This has been due not so much to lower amounts of capacity eventually being installed as to the delays generally incurred in the completion of the plants built under the 28 loans under review in this section. These loans have led to the construction and/or extension of 71 identified generating plants, of which 39 are hydroelectric and 32 thermal; CFE accounts for a major part with 24 plants of each type. Total installed generating capacity, amounting to 9,318 MW, was higher than forecast (8,167 MW). However, substantial delays were the rule in the construction and commissioning of generating plants as shown in the following table:

TABLE 14.6: AVERAGE DELAYS IN INSTALLATION OF PLANTS

	Average Delays (months) in:	
	Commissioning Dates	Construction Periods
Plants other than CFE's	7.2	5.3
CFE Plants	16.5	13.1
All Plants	12.4	6.6

On average, the 71 plants were commissioned with delays of about 12 months, (7 months, leaving aside the CFE plants, which were commissioned with an average delay of about 16 months); the average one-year delay in commissioning dates has resulted to the extent of nearly one-half from delays in initiating the construction and one-half from delays in the construction periods (without CFE, the average delay in initiating the construction was two months only, while the average delay in construction period was five months). These substantial delays in plant commissioning dates have generally not (except in the case of EELPA briefly in the mid-1960s and in the three Colombian companies, especially in the early 1960s) hampered the companies in meeting demand; rather, they had the effect of substantially reducing the amounts of gross reserves allowed for in forecasts.

3.03 In generation facilities, the traditional prominence of hydroelectric schemes in Bank lending clearly emerges from this review. The 39 hydroelectric plants, with sizes ranging from 10 MW to 900 MW, total 6,054 MW, of which 2,530 MW in Mexico. The construction period of the hydroelectric plants was about 5 years in average, with a maximum of nearly 9 years for the 160 MW Miguel Aleman system in Mexico and a minimum of 2 years and a half for the 32 MW Awash II plant in Ethiopia (see Appendix Table 14.3 for details). The 32 thermal plants, with sizes of generating units ranging from 5 MW (excluding small 1 and 2.5 MW units installed in the mid-1950s in Mexico) to 250 MW, total 3,260 MW, of which 1,860 MW in Mexico. The construction period of thermal plants was noticeably shorter than for hydroelectric plants, averaging about 3 years, with a maximum of 5 years for the 5 x 120 MW Costanera plant in Argentina and a minimum of

21 months for a 3 x 5 MW plant in Mexico. Several of the hydroelectric plants, but none of the thermal plants, have been built substantially more quickly than originally forecast (Estreito in Brazil, Akosombo in Ghana, the Cameron Highlands schemes in Malaysia, and three plants of the Oriental system in Mexico); however, construction periods generally were noticeably longer than forecast for all other hydro plants, in particular in Colombia and Mexico where delays averaged 10 and 12 months respectively while delays were about 5 months in other countries. On the other hand, forecasts of the construction period have been much more accurate for the thermal plants (except for the Zipaquira plant in Colombia) which were on the average built with construction periods similar to those forecast, as might be expected in view of the lesser dependence on natural phenomena.

3.04 Among all hydro plants, there are numerous cases of serious overrun on construction time. Construction of the small Awash III plant in Ethiopia took about 80 months, nearly twice as long as originally expected, due to inadequate original design and serious difficulties with rock conditions; these delays fortunately did not hamper EELPA in meeting the demand, although much shorter delays in 1966 on the comparable Awash II plant, also financed by Bank, did require temporary restriction of load. There was also overrun on Stage I of the Furnas plant, which took 85 months compared to the planned 60 months, but this was mainly due to substantial redesign of the plant to increase capacity, although some difficulties were also encountered with rock conditions.

3.05 In Colombia, the construction delays of 1 and 1.5 years incurred respectively on the Troneras and Guadalupe III plants of EPM were due mainly to the under-equipment and poor direction of the contractors who were also handicapped by price increases on imported equipment occasioned by the Government's import restriction policy. The delays of about 2 years in commissioning the plants of CVC/CHIDRAL were due in the Anchicaya plant mainly to technical difficulties caused by a landslide at site and by restrictions on equipment importation, and in the Calima plant to difficulties with rock conditions and supply of raw material for the dam, to the contractor's poor organization and equipment and to difficulties in raising finance for covering cost overruns. The delays ranging between 6 months and 18 months in commissioning the 3 hydroelectric plants of EEEB occurred as a result of technical (geological and sealing) difficulties in the construction of Salto II and El Colegio plants and as a consequence of problems with the contractor for Salto II. Delays in the construction of the plants resulted in significant power shortages on CVC's system in the 1950s and, in the 1960s, especially in 1964 and 1965. Shortages in the EEEB and EPM systems which had begun in 1959 were also extended to 1962/63 as a result of the delays in completion of the first Bank-financed projects in each city.

3.06 In Mexico, the delays of about two years in the completion of the construction programs covered by the first two loans were caused mainly by the considerable revisions and uncoordinated changes made on the programs, which had been poorly planned and prepared, by the lack of local funds in the early 1950s for the first program, and by CFE's lack of experienced staff, which led to technical errors. The River Diversions scheme of the Miguel Aleman system, covered in the first loan, suffered large delays as a result of deficient design and inadequate subsoil investigations. In the program financed by the third loan to Mexico, delays in commissioning and construction of plants ranged between 10 months and 18 months, being particularly long on the Mazatepec project involving a thin arch dam which required careful geological investigations and supervisions by an International Board of Consultants recommended by the Bank. Substantial overruns in construction time were continuously incurred on the hydro plants included in the last three CFE programs, especially on the large plants of Infiernillo and Malpaso and on many smaller plants (San Bartolo II, Sanalona, La Venta, Chilapan, El Retiro, El Salto and El Fuerte). These delays were due to technical problems, to CFE's difficulty in handling programs of rapidly increasing scale, as well as partially to the desirability of slowing down the expansion of capacity in view of slower than expected load development.

3.07 Total cost of the 39 hydroelectric plants, excluding the cost of associated transmission facilities, amounted to $1,105 million equivalent for 5,838 MW installed against $822 million forecast for 5,028 MW (both excluding 216 MW installed in Colombia, because of lack of data on actual costs). Primarily due to the cost overruns incurred in Colombia and Mexico, actual unit costs averaging $189 per kilowatt installed exceeded forecasts which averaged $164, as shown in the Table 14.7, which summarizes the detail given in Appendix Table 14.3.

3.08 The impact of the Colombian and Mexican projects on the unit cost overruns is strong since without these projects the actual cost averaged \$179 per kilowatt installed compared with \$223 forecast. Actual unit costs ranged from \$127 on the Colombian Guadalupe III plant of 270 MW (excluding the Mexican Malpaso plant of 720 MW, the cost of which relates only to the power part of the scheme which had been built for irrigation purposes) to \$592 on the exceedingly expensive 30 MW La Venta plant in Mexico (see Appendix Table 14.3 for details). Unit costs were lower than forecast on the hydroelectric plants outside Colombia and Mexico, except for the Ethiopian Awash III and Stage II of the Malaysian Cameron Highlands scheme; on the other hand, the savings on unit costs were noticeably large on the Stage I of the Cameron Highlands scheme because of very good bids and conditions for civil works, and on the Furnas plant due mainly to the redesign of the plant involving substantial increase in the size of the units and of the whole first stage of the plant. For all plants built outside of Colombia and Mexico savings on unit costs averaged about 10%. Hydroelectric plants built in Colombia had unit cost overruns averaging 25%, with the highest overruns on the Calima and Troneras plants due principally to increased local expenditures (Chapters XI and XII). In Mexico, estimates of local costs on hydroelectric plants were constantly exceeded by far, resulting in unit cost overruns averaging 76%; overruns of about 10% were experienced on the small Sanalona and El Fuerte plants but in most cases overruns were higher than 50%, reaching more than 150% in the cases of Malpaso, Cupatitzio, and the group of plants on the Oriental System which was financed in the 1950s. The actual average ratio of foreign to domestic cost on the non-Mexican hydroelectric plants was 47/53; on the Mexican plants for which the breakdown is available this proportion reached 20/80, so that on all plants the ratio decreased to 40/60.

3.09 Total cost of the 32 complete or extended thermal plants amounted to \$560 million for 3,230 MW installed, as against \$468 million forecast for 2,890 MW (both excluding one 33 MW unit in Colombia for which no actual cost is available). The actual overall average unit cost was thus \$174 per kw installed, exceeding the average forecast of \$162/kw by less than that on the hydroelectric plants. The overrun on the average unit cost of thermal plant was primarily due to the Mexican plants, since the average unit cost on non-Mexican plants was \$178/kw as against \$184 forecast; since the actual unit cost on Mexican plants averaged only \$168/kw, this indicates that the overrun was due to unreasonably low cost estimates in Mexico. On the other hand, cost estimates for the non-Mexican plants have been much more accurate, exceeding actual costs by only 2% on average; there were, however, important savings over original cost estimates for some stations such as NEB's Port Dickson I and Johore Bahru and SEBGA's Puerto Nuevo ninth unit, but not generally of comparable magnitude with the savings experienced on some of the hydroelectric plants. Cost increases on Mexican plants were generally substantial, averaging 37% of estimates, but of much smaller magnitude than those experienced on the hydroelectric plants in Mexico; actual costs were generally very similar to those in other countries, except for the 41 MW units of the Guaymas and Topolobampo plants for which they were unusually high and the 37.5 MW units of the Rio Bravo plant which were particularly inexpensive. The very high cost of the 120 MW units of SEGBA's Costanera plant resulted principally from the original bilateral financing and procurement arrangements, from the long delays in construction and from the large component of equipment procured from domestic suppliers at prices above international levels (Chapter II).

3.10 The detailed data of Appendix Table 14.3 and the Chart 14.1 show that actual unit costs ranged between \$330/kw on the Mexican Juchitan station with 2 x 6.25 MW units and \$120/kw on the Mexican stations of Valle de Mexico and Salamanca II with 150 MW units; this range does not include the 250 MW ninth unit in SEGBA's Puerto Nuevo Station, which has a unit cost (\$125/kw) slightly above the general tendency, nor the 14-15 MW gas turbines which have a unit cost of about \$100 to \$150/kw. Not taking into account most of the small units built in Mexico during the early 1950s with costs substantially lower than those of similar units built after 1960,[1/] the Chart indicates somewhat decreasing reductions in unit costs as the scale of the thermal generating units increases. For instance, between a very small unit and 20 MW costs decrease from some \$330/kw to about \$250/kw, a total of \$80 or, in other words, \$4 per kilowatt for each MW increase in capacity; whereas, between 60 and 80 MW costs decrease from some \$165/kw to \$145/kw or only about \$1 per kilowatt for each MW increase in capacity. A rough adjustment on the average trend gives the following pattern:

TABLE 14.8: DECREASING RETURNS TO SCALE ON THERMAL UNITS

Range of unit size (MW)	0-20	20-40	40-60	60-80	80-110	110-150
Reduction in costs per kw for each additional MW of capacity (\$)	4	2.5	1.75	1	0.5	0.25

1/ This would suggest that manufacturing cost increases in supplier countries are reflected in Chart 14.1; for this reason, points referring to plants built before 1958 are shown in red.

The proportion of foreign to domestic cost for thermal plants does not differ very greatly between Mexico and other countries, the average pattern for all cases together being 58/42; however, in the thermal plants built outside Argentina and Mexico the pattern averaged 68/32 while in Mexico it was 56/44 and, on the Argentine Costanera plant, 52/48, both of these latter figures reflecting the increasing importance of the local industry in these two countries.

3.11 A small amount of data has been collected from four utilities about the costs of other generating plants, not financed with Bank assistance. This is far from being sufficient to permit any conclusions, but it tends to suggest that Bank-financed plants can in some instances be somewhat cheaper. For instance, the 80 MW units of the Santa Cruz thermal plant completed by Furnas in 1967/68 with USAID participation have a unit cost of $208/kw, substantially higher than the unit costs experienced in the Mexican Tijuana plant ($164/kw for 75 MW units and $129/kw for one 82 MW unit); the 120 MW units of the Argentine Costanera plant, supplied and financed by a British consortium in a manner not consistent with the classical procedures of the Bank, had exceedingly high unit costs ($229/kw as compared with $120/kw in Mexican plants); also the unit cost of the Jurong station (4 x 60 MW units) in Singapore, built in 1967/71 without Bank participation is about $150/kw, compared with $138/kw for the quite similar Pasir Panjang station (4 x 60 MW units) built with Bank assistance. On the other hand, the Jurong unit cost is about 10% smaller than that experienced in the Bank-financed Port Dickson I plant of NEB built in 1966/69 but with only two 60 MW units initially; also the 4 x 10 MW Malacca plant of NEB built in the early 1960s without Bank assistance apparently has a unit cost of $212/kw which compares favorably with the $290/kw cost incurred on the plants of Veracruz in Mexico and Yumbo in Colombia equipped with 10 MW units. Hydroelectric plants are much more difficult to compare with one another. Nevertheless, it is interesting to note that none of the Bank-financed hydroelectric stations had unit costs approaching the $404/kw of Furnas' Funil plant (210 MW) or the $646/kw of EELPA's Tis Abbai plant (9.6 MW) which can be compared respectively to CFE's Mazatepec plant[1/] (208 MW with $319/kw) and El Retiro plant (20 MW with $552/kw); on the other hand, EELPA's Awash I station of 43 MW, financed bilaterally, cost the same per kilowatt installed as the Bank-financed Awash II and III stations of slightly smaller size.

3.12 The quality of the technical and financial information available from both the appraisal reports and the utilities on the transmission and distribution projects and components of projects does not provide an equally firm basis for judgment on the Bank's action in this field; this is partly due to the large amount and great diversity of technical specifications and small-size equipments involved in these projects which would require, for any comprehensive review, a larger amount of research than could be accomplished within the time-frame of the present study. In transmission, about 17,500 km of circuit lines between 115 and 400 kv were built under the projects and construction programs financed by the Bank, of which 12,600 km[2/] in Mexico; available data suggest that overruns in construction

1/ Both Funil and Mazatepec plants were built with thin arch dams.
2/ For which costs are available.

periods were minor, except in Colombia, and that small cost savings were generally made, except in Malaysia and Argentina due to topographical difficulties (mountains and urban environment respectively). The unit cost per kilometer of circuit-line installed (including associated substations) averaged about $30,000 compared to $31,800 forecast; unit costs ranged from about $8,000/km on Mexican lines at the lower end of the voltage range cited to more than $100,000/km in SEGBA's urban subterranean transmission network which was built with expensive equipment mostly from local manufacturers (see Appendix Table 14.3 for details).

3.13 Extensions made with Bank assistance to five distribution networks led to the installation of about 17,800 km of circuit-lines in primary and secondary networks, excluding the distribution projects and programs implemented in Mexico. Available data suggest that economies of about 30% relative to forecasts were made, except in Colombia, on the unit costs per km installed, which averaged $14,600/km compared to $21,300/km forecast. Larger economies on unit costs were made in Ethiopia and also in Singapore where the cost is nevertheless high at $61,000/km due to the subterranean nature and to the ample, if not excessive, dimensioning of the network; the unit cost was $15,000/km on SEGBA's subterranean network which, on the other hand, still requires strengthening. The Bank's participation in the $147 million distribution expansion programs undertaken in Mexico during 1962-1966 amounted to $39.2 million; unfortunately, neither forecast nor actual data on the content of these programs are available.

3.14 The proportion of foreign to domestic costs in transmission projects has varied extensively from 19/81 in Argentina, due to large-scale procurement from local suppliers, to 76/24 in Ethiopia and Ghana where there has been no local industry for electrical equipment; in countries other than Argentina the average pattern was 57/43. For distribution projects, excluding Argentina and Mexico for which the breakdown is not available, the proportion of foreign to domestic costs was higher than for transmission, averaging 69/31.

3.15 Finally, the Bank participated on a generally minor scale in rural electrification projects in several countries, including Mexico in the early 1950s and Ethiopia. The two projects for which data are available were built with costs substantially lower than forecast. Unit costs averaged $330/kw installed in diesel plants compared to $600 estimated. The Bank also contributed $16.5 million to the rural electrification programs undertaken in Mexico during 1962-1966 with a total cost of $33.5 million, but details are not available on their composition.

IV. The Bank's Effect in the Financing of the Construction Programs

4.01 IBRD loan commitments for the ten utilities under review amounted to $1.5 billion by the end of 1970, distributed among 39 loans. Total Bank Group commitments for power by the same date amounted to $5.4 billion in 232 loans. The average size of the loans made to the ten companies is considerably higher than the average size of all Bank Group loans for power ($39 million against $23 million). Moreover, the importance of the Bank's role in power in the American continent, as depicted in Chapter I (paras. 3.02 and 3.03), is further emphasized in the current study since the share of Latin American utilities in aggregate disbursements out of the 39 loans covered has been 80%, against 58% in total Bank Group disbursements for power, as shown in the following table:

TABLE 14.9

THE TEN COMPANIES: BANK-FINANCED SHARE OF CAPACITY EXPANSION 1960-70, CUMULATIVE TOTAL AMOUNTS DISBURSED THROUGH 12/31/70, AND TOTAL DISBURSEMENTS FOR POWER BY WORLD REGIONS

	Increase in Capacity 1960-70 Total (MW)	Increase in Capacity 1960-70 Bank-Financed (MW)	IBRD Total Amount Disbursed ($ mln)	Total Bank Group Disbursements for Power a/ ($ mln)
Africa				
EELPA	85	74	27.3	
VRA	588	588	47.1	
Subtotal	673	662	74.4	291.3
America				
SEGBA	1,147	970	151.6	
Furnas	2,294	1,600	127.0	
EEEB	460	455	78.1	
EPM	306	306	67.9	
CVC/CHIDRAL	153	153	44.6	
CFE	4,298	3,881	448.1	
Subtotal	8,658	7,365	917.3	1,757.5
Asia				
NEB	514	500	108.6	
PUB	467	240	49.0	
Subtotal	981	740	157.6	809.9
Grand Total	10,312	8,767	1,149.4	3,022.7 b/

a/ To developing countries of over 1 million inhabitants (see Table 1.3 in Chapter I).

b/ Including $164 million disbursed to European developing countries.

The emphasis placed in this review on Latin American countries, evidenced also by the Bank-financed capacity and its share in the capacity increases over 1960-70, is partly explained by the need to select companies which had had fairly long and continuous relationships with the Bank in order to evaluate the nature and effectiveness of the Bank's efforts on institutional development. The facts and judgments presented in this section might thus be biased towards common Latin American patterns; nevertheless, many features of power utilities are similar so that somewhat general conclusions can probably fairly be drawn.

4.02 The investment programs partly financed by the Bank loans fully or nearly fully disbursed during the period 1958-70, and under which 8,853 MW of generating capacity and other power facilities were installed, had total requirements of funds of $4,230 million, excluding CFE's pre-1958 programs and all CVC/CHIDRAL programs, for which no data are available regarding sources and applications of funds. For the nine companies together, total foreign borrowing contributed half to total requirements of funds; about half of foreign borrowing (i.e. one-fourth of total funds) came from the Bank, the other half originating mainly from foreign private loans and supplier credits and, to a very small extent, from bond issues and bilateral official assistance (see Chapter XVII). The minor share from the private sector (customer contributions, and principally local commercial banks) together with loans from the public sector accounted for one-third of the total local currency contribution (which also provided one-half of total funds required); equity contributions from the public sector and the companies' internal generation of funds shared equally the remaining two-thirds, each representing thus about 16% of the total requirements of funds.[1/] The overall financing pattern is heavily influenced, however, by that of Mexico which accounted for about half of the $4,230 million total requirements of funds.

4.03 Excluding the Mexican power sector which received most of the foreign bonds and private contributions (both local and foreign) and more than two-thirds of the supplier credits and public share capital, the financing pattern of the eight non-Mexican utilities is substantially different; foreign borrowing then contributed 40% to total required funds, with the Bank contribution representing three-fourths of foreign borrowing -- i.e. 30% of total funds -- and the remaining fourth coming mainly from supplier credits and bilateral official assistance while foreign private loans became negligible and proceeds of bonds issues remained very small. Within the total local currency contribution, which represented a greater part (60%) of total funds, the share of the private sector became negligible and the contribution from the public sector stood at about one-fourth of total funds, consisting mainly in loans from governmental and public institutions; net internal cash generation of the eight companies represented almost 50% of the total local currency contribution, i.e. 28% of total requirements of funds.

1/ In Table 14.10 the proceeds of the Power Consumption Tax levied on all electricity sales in Mexico, which are handed over in total to CFE, are treated as part of government equity contribution, for comparability with other companies. If treated as CFE internal cash generation, then total internal cash generation for all the companies together would be about 25% of total requirement of funds, and government equity contributions would be only about 10%.

4.04 The financing pattern of the Mexican power sector after 1958 diverges substantially from that of the other companies. Foreign borrowing contributed 60% to total requirements of funds, an important source being foreign private banks, which accounted for one-third of foreign borrowing and one-fifth of total sources of funds; the Bank contributed slightly less than one-third of foreign borrowing -- i.e. 18% of total sources -- and supplier credits plus foreign bonds contributed the remaining substantial share. The contribution from the Mexican private sector (mainly from local banks) was exceptionally significant, compared with the situation for the other companies, representing one-fourth of total local currency contribution and 10% of total sources. The proceeds of the Power Consumption Tax, which accounted for one-third of total local contribution and for 13% of all sources, creates difficulties in comparing the financing pattern of the Mexican power sector with that of other companies. If, for strict comparative purposes, these proceeds are included in the Government's equity contribution, then the latter has constituted more than half of total local contribution (or one-fourth of total funds), and net internal cash generation from the power sector only one-tenth of local contribution (or 4% of total sources), which is a remarkably low percentage in comparison with other companies. On the other hand, when the proceeds of the Power Consumption Tax are included among the revenues of the power sector, following the procedures used by the Bank since 1962 (see Chapter VII), then net internal cash generation of the sector has contributed 17% to total requirements of funds -- which is still a small proportion compared to other companies -- while the share of the public sector and of its equity contribution is reduced by half. In either case, the contribution of the public sector (27 or 14%) has been minimized to the extent that it does not take into account the important loans made in 1965-68 by Nacional Financiera S.A., the Mexican official development bank, to refinance the power sector's debt to an amount of $178 million, equivalent to 9% of all funds required.

4.05 The case of the Mexican power sector also differs substantially from other companies in respect of the general tendencies over time that may be inferred from study of the forecast and actual sources of funds in the financing plans related to the successive loans. This is shown in the following Table 14.11, which compares the actual financing patterns with the Bank's forecasts, the latter reflecting to some extent the financial objectives pursued by the Bank. Details are given in Appendix Table 14.4 at the end of this chapter. The following discussion will be based on all the data, except those for Mexico, which was shown to be a particular case, and those for EELPA and VRA for which comparisons over time are not possible, each having had only one loan which was fully or nearly fully disbursed by the end of 1970. The forecast financing patterns for the first loans indicate that the Bank expected the borrowing companies to be on a sufficiently sound financial basis that they would be able to generate internally one-third of total requirements of funds on average (non-weighted in order to avoid bias from large companies); and they would obtain about one-half of total funds required from foreign borrowing, the Bank contributing about one-third of total funds and domestic institutions a minor part. Though actual developments experienced with the first loans generally departed noticeably from expectations (para. 4.06) and forecasts for

TABLE 14.11: EVOLUTION OVER TIME OF THE ACTUAL AND FORECAST COMPOSITIONS OF SOURCES OF FUNDS

(in percentages of total sources)

	Average Pattern (excluding CFE, EELPA, VRA) a/ first loan to utility	Average Pattern (excluding CFE, EELPA, VRA) a/ last loan to utility c/	Average Pattern in Mexico b/ first loan to utility	Average Pattern in Mexico b/ last loan to utility c/	Average
ACTUAL					
1. Net Internal Cash Generation	25	40	9 (23)	- (13)	5 (19)
2. Other Domestic Contributions	32	18	46 (32)	32 (19)	39 (25)
3. Foreign Borrowing: Total	43	42	45	68	56
of which IBRD	38	32	12	15	16
Total	100	100	100	100	100
FORECAST					
1. Net Internal Cash Generation	33	38	20	26	16 (36)
2. Other Domestic Contributions	19	15	49	31	39 (19)
3. Foreign Borrowing: Total	48	47	31	43	45
of which IBRD	34	42	31	34	32
Total	100	100	100	100	100
Total Funds: Forecast / Actual	.87	.103	.57	.83	.70

a/ EELPA and VRA were excluded because they have received only one loan fully or nearly fully disbursed, thus preventing analysis of evolution over time in these two companies.
b/ Figures in brackets allow for inclusion of Power consumption Tax within revenues.
c/ Most recent loan to each company fully or nearly fully disbursed.

following loans were to some extent corrected accordingly, the Bank expected when making its most recent loans (among those fully or nearly fully disbursed) that increased internal cash generation would contribute up to 38% of total funds and Bank loans' share would increase to 42%, while the contribution from domestic sources other than internal cash generation would remain minor.

4.06 On the average, developments experienced with the first loans did not meet the Bank's expectations. In particular, internal cash generation contributed only one-fourth to the cost of the first programs financed with Bank assistance, because the cost of these first programs generally exceeded the estimates by about 15% (except in the cases of Furnas, Chapter III, and EPM, due to large delays incurred on construction, para. 3.05), and because sales were generally overestimated (para. 2.02). As a consequence of the cost overruns, the contribution of foreign borrowing, at 43%, was lower than forecast, and the domestic contribution (mainly loans from the public sector) had to compensate for the shortage of internal cash and foreign borrowing, contributing one-third to total program costs -- that is, more than 1.5 times forecast. Though disbursements from Bank loans began later and were made at a slower rate than expected (para. 4.10), the Bank's share in total funds was slightly higher than expected, due either to lower costs of the investments (Furnas, EPM) or to additional Bank loans originally unforeseen (NEB).

4.07 Financing patterns of the investment programs partly financed by the most recent Bank loans fully disbursed and generally made six years after the first one received by each company tend to suggest that marked improvements and financial strengthening of the companies took place.

On average, internal generation of funds increased considerably to cover up to 40% of total costs of the programs, which in turn had increased substantially and had been more accurately estimated; though the share of Bank loans decreased compared both with forecasts and with experience under first loans to 32% of total cost, the utilities were able to obtain other foreign loans in increasing amounts such as to maintain the share of foreign borrowing at a roughly constant level. Domestic contributions from other sources decreased in line with the increase in net internal cash generation. This substantial improvement in the financial situation of the companies and in their creditworthiness to bilateral or private foreign lenders seems to reflect in part the almost continuous respect of the covenants agreed with the Bank for setting tariffs at levels sufficient to generate large internal contributions to the costs of investment (see Section 5 below).

4.08 Among the individual companies there are, however, significant variations from the average pattern of development described above. In SEGBA, the Bank's contribution to the 1962-64 and 1968-70 investment programs remained constant at about 30% of total cost, while there was decreasing use of supplier credits; other domestic contributions, mainly equity from the Government for the first program and loans from private local banks for the second program, dropped radically from 21% to 4% of total sources; probably partly due to the Bank's pressure on the Government to respect SEGBA's concession agreement and permit timely tariff adjustments, internal generation of funds more than doubled in relative terms, though it increased less in absolute terms due to the substantially smaller size of the second investment program (Chapter II). In Brazil, the size of Furnas' investment program more than doubled between the periods 1958-65 and 1964-70; as a result, foreign borrowing as well as Bank loans decreased in relative importance while increasingly large contributions were made by the public sector, mainly in the form of loans from the Federal power agency (Chapter III); internal generation of funds, which had been minor during the 1958-65 period of establishment of the company, contributed as expected one-third to the cost of the second investment program -- even though it turned out to be much larger than expected at the time of project appraisal. This strong performance was possible mainly because of the 1964 tariff legislation which permitted Furnas to earn substantial returns on its investments and which the Bank had strongly promoted. Furnas' second investment program was one of the rare ones to be supported almost equally by the Bank and an official bilateral assistance agency (USAID).

4.09 In Colombia, the Bank has been virtually the only source of foreign funds to EEEB and EPM, except for EEEB's last investment program which received supplier credits under joint financing arrangements; domestic sources, representing about one-fifth of total funds, were municipal contributions; returns from tariffs enabled the two Colombian companies to generate internally about one-third or more of total funds, except EEEB in 1960-62 and 1962-65 (Chapter X). EPM's investment programs typically had lower costs during the planned periods than expected, due mainly to lengthy construction delays. In Malaysia and Singapore, the share of foreign borrowing (originating mostly from the Bank) increased over time, more in Singapore than in Malaysia due to the substantial supplier credits obtained for PUB's second investment program; domestic contributions, mostly from the public sector, decreased in relative and absolute terms, the Governments reducing their loans to both utilities, which earned returns sufficient to increase up to about 40% their own contribution to the cost of the programs.

4.10 In Ethiopia, foreign borrowing, almost entirely from the Bank, contributed two-thirds to the 1964-68 investment program, the remaining third being financed by EELPA's own funds earned from relatively high tariffs (Chapter IV). In Ghana, the construction of the Volta River project during 1962-1965 was financed by Government equity and foreign borrowing in relative proportions 42/58; due to the small returns earned by VRA (Chapter V), net internal cash generation could contribute only 10% to the cost of the small investments made since 1966, with foreign borrowing from the Bank and mainly from bilateral official donors financing the rest. In Mexico, total local currency contribution to the huge investment programs of 1958/62, 1962/65 and 1968/69 has been steadily decreasing over time from 55% to 32%, the reductions occurring in the shares of both net internal cash generation of the sector and the contribution from the public sector; among foreign sources, Bank loans have contributed a somewhat constant minor share to total funds while the important supplier credits of the 1958-1965 period were replaced after 1965 by large amounts of borrowing on foreign capital markets (bond issues) and from foreign commercial banks.

4.11 With the exception of the special cases of CFE and VRA (and CVC/CHIDRAL) self-financing performance of the companies has shown marked improvements during the time the Bank has been lending to them and this is probably partly due to the Bank's coordinated actions on institutional development and tariff levels (see also Chapter XV). Initial associations between the Bank and the borrowers (including CFE) were generally marked by poorer performance of the companies than expected with regard to internal self-financing and ability to raise other foreign funds; this was usually offset by larger domestic contributions than foreseen, mostly from the public sector. Over time, the situation has gradually improved to levels beyond the Bank's expectations and objectives; the most recent investment programs financed with the Bank's assistance indicate that self-financing has on the whole been high - often around 35-40% - and in several cases higher than expected, in particular in PUB, NEB and the Colombian companies, thus allowing the Government authorities to withdraw partly from the power sector and to divert increasing funds to other weaker utilities and/or other sectors; moreover the companies have become less dependent on Bank loans and more capable through increased creditworthiness of diversifying their sources of foreign funds, mainly in the form of supplier credits and official or private loans, sometimes obtained with the Bank's assistance.

4.12 One further dimension of the Bank's financial contribution deserves to be mentioned, that is the efficacy with which Bank commitments materialized in the form of actual disbursements. Two significant indicators of the disbursement patterns were found to be the 10% and 82.5% cut-off percentages of the cumulative disbursements. Before the 10% level was reached, disbursements had often been slow due to initial uncertainties about procedures and procurement, and after the 82.5% level was reached, disbursements often slowed down due to minor problems in bringing all aspects of the project to ultimate completion and withholding of final payments to contractors and suppliers pending fully effective operation of plant; between these two cut-off percentages disbursements tended to follow a more regular pattern. Data for the 28 loans under review which have been fully or nearly fully disbursed are summarized in the following table.

TABLE 14.12

PERIODS (IN MONTHS AFTER SIGNING DATES) NECESSARY TO REACH THE 10% AND 82.5% CUT-OFF POINTS ON CUMULATIVE DISBURSEMENTS

	Overall Average (28 loans)	Average on first loans	Average on latest loans
Forecast			
10% cut-off	6	5	6
82.5% cut-off	30	31	28
Rates (in % per month a/)	3.0	2.8	3.2
Actual			
10% cut-off	9	10	11
82.5% cut-off	39	42	29
Rates (in % per month a/)	2.4	2.2	4.0
Delay between signing and effectiveness	3	4	3

a/ i.e. between the two cut-off points.

Disbursements have generally occurred later and at a slower rate than expected. During the regular phase of disbursements (between the 10 and

82.5% cut-offs) disbursement rates have generally been 20% slower than expected. Here again, however, improvements have been made over time and with increased experience, since the number of months necessary to reach 82.5% of disbursements was substantially shortened, and disbursement rates increased for last loans as compared to first loans.

V. Operational Performance of the Companies

5.01 One of the general objectives of Bank action in the electric power field has been to assist and promote the growth of companies which would be efficient suppliers of electricity. Many institutional and financial conditions have been laid down by the Bank in connection with its lending for electric power, as seen in previous chapters, and one of the general purposes of such conditions has been to promote efficiency. Moreover, irrespective of the Bank's direct efforts, it is clearly important how efficient and effective are the companies with which the Bank has been associated through its power lending and what trends they have displayed over time. Various aspects of this are treated at various places in the report. The purpose of the present section is to review systematically, and on a comparative basis, what is shown by the summary indicators of company performance gathered for each entity under review and presented in the Table I at the end of each of the company chapters (Chapters II - VIII and X - XII).

5.02 Appendix Table 14.5 shows the values taken by a common set of operational, financial and management indicators for each of the ten companies in three selected years, 1960, 1965 and 1970. Table 14.13 below summarizes the trends experienced over the last decade on some of these indicators.

TABLE 14.13

GROWTH IN SELECTED BASIC INDICATORS OVER THE PERIOD 1960-70

(in average annual rates of increase, %)

	Installed Capacity	Peak Load	Energy Sales	No. of Customers	Labor Productivity a/	Net b/ Revenues	Average net fixed assets in service
SEGBA	10.2	12.4	11.1	7.6	6.0	12.2	16.8
EEEB	16.5	14.0	12.9	8.1	6.5	8.0	12.1
EPM	12.4	9.5	7.7	5.7	8.9 e/	10.0	7.3 f/
CVC/CHIDRAL	10.1	13.1	13.5	-	n.a.	12.0	15.3 f/
EELPA	11.4	17.0	19.1	13.3	8.9	16.7	11.1
NEB	15.9	14.5	14.9	10.0	8.1	18.4	16.9
PUB	13.8	12.3	12.9	10.5	5.9	19.9	10.1
Average	12.9	13.3	13.2	9.2	7.4	13.9	12.8
CFE	17.2	10.5g/	17.8	23.7 h/	4.1	22.8	20.3
FURNAS c/	20.6	29.4	19.3	-	11.4	42.8	17.8
VRA d/	-	6.0	24.5	-	21.2	48.8	1.7

a/ Annual energy sales per employee.
b/ Net revenues from sales only, including indirect taxes on electricity consumption and before direct taxation on utility, in approximately real terms.
c/ For Furnas, average annual increase rates over 1965-70.
d/ For VRA, average annual increase rates over 1967-70.
e/ Average annual increase rate over 1964-70.
f/ Average annual increase rates over 1960-69.
g/ Average annual increase rate of non-coincident peak load in Mexico.
h/ This number allows for substantial acquisitions and absorption into CFE of other companies. The average rate of growth between 1962 and 1970 for all electrical utility customers in Mexico has been 10.3% p.a.

Even leaving aside the special cases of CFE (with its absorptions) and Furnas and VRA, the two bulk suppliers which only started operations in the 1960s and have been going through a phase of rapid initial growth, it is striking that the basic growth trends shown for the various companies are on the high side compared with the averages for the developing countries as a whole, and for various regions, discussed in Section II of Chapter I. This applies particularly to the Latin American utilities in the review, which contrast with the relatively slow overall growth of utility supplies of electricity in Latin America indicated in Chapter I.

5.03 Taking all the companies together (other than CFE, Furnas and VRA), installed generating capacity and average net fixed assets in operation have been growing at almost identical rates of about 13% p.a., suggesting that the cost of generating assets has been at least stable if not decreasing over time. Peak loads and energy sales have been growing at rates slightly above installed capacity of about 13.2% p.a. - which compares with 11.6% on average over 1960-68 for the developing member countries of the Bank Group as a whole (see Chapter I). In all cases, the number of customers has been growing at a slower rate than sales, indicating an average annual increase of about 4% in kwh consumption per customer. Net revenues from sales have generally been growing slightly faster than sales, indicating that average profits per unit sold have increased over time (see also Table 16.1 in Chapter XVI), but this does not hold true for some companies, particularly EEEB, CVC and EELPA.

5.04 Labor productivity, defined by the energy sales per employee, has been growing rapidly at more than 7% p.a. on average, a higher growth rate than that for developed countries. The broadest indicator of the financial situation and management of the utilities is in many ways the rate of return on the capital invested. The following table gives for each utility the trends over time of the rate of return, based for comparability on a standardized concept which relates the net revenues from electricity sales, including indirect taxes on electricity consumption, after adequate provision for depreciation and before interest and direct taxation, to the average net fixed assets in operation, revalued where necessary to allow for sizeable inflation.

TABLE 14.14

STANDARD RATES OF RETURN (%)

	1960	1963	1965	1967	1970	Average g/ 1960-70
SEGBA	16.2	11.9	13.5	11.4	10.9	13.9
FURNAS	-	0.9	12.5	17.0	18.7	15.8 c/
EEEB a/	15.7	9.1	9.1	7.8	9.9	10.4
EPM a/	14.8	8.7	7.2	6.0	11.0 d/	9.5
CVC/CHIDRAL a/	6.3	2.0	3.7	2.5	4.2 d/	3.9
EELPA	5.9	6.4	8.3	9.2	9.8	7.4
NEB	7.6	7.6	8.2	10.1	8.7	8.5
CFE b/	4.8	5.4	5.0	9.7	8.5	7.0
PUB	8.1	11.6	7.0	11.0	18.9	11.5
Average g/	9.9 e/	7.0 e/	8.3	9.4	11.2	9.8
VRA	-	-	0.4	0.6	4.3	2.5 f/

a/ Rate of return on assets revalued as shown in Annex I.
b/ Rate of return after corrections for depreciation as calculated in this report.
c/ Average over 1964-70.
d/ For 1969; data not available for 1970. Averages are over 1960-69.
e/ Excluding FURNAS which started operating in late 1963.
f/ Average over 1966-70.
g/ Averages are unweighted.

5.05 In most of the utilities covered, except Furnas, EELPA and the special case of VRA, the rate of return has shown in the middle 1960s significant decreases which were generally, but not in all cases, more than offset in the very late 1960s. The declines were in part due to special difficulties encountered in several countries studied, in the early and middle 1960s, in increasing tariffs to keep up with inflation; also in some cases very sharp increases in assets affected returns. On average over all utilities (except VRA, see Chapter V), the standardized rate of return has been satisfactory, averaging 9.8% over 1960-1970. However, the standard rate of return concept used here does not generally correspond to the rate of return concepts used in Bank covenants with the various companies, due to the special corrections made here (for the 3 Colombian companies and for CFE) and, more importantly, to the inclusion in net revenues of somewhat sizeable indirect taxes on electricity sales, as in the case of SEGBA, Furnas, EELPA, CFE, and also PUB after 1968.

5.06 Though the broad picture given above has been generally satisfactory, many of the companies did in the past depart from satisfactory trends and sound financial practices. These departures raised concern in the Bank. They are highlighted here by the comparison with other companies, in particular with the "model" ones which have operated satisfactorily in most respects. Within this review, three companies can be taken, still with some reservations, as "model" companies for the other ones, i.e., Singapore's PUB, Brazil's Furnas and Malaysia's NEB.

5.07 The PUB of Singapore has been serving a predominantly urban area and as such can be compared to three other similar companies, SEGBA in Buenos Aires, EEEB in Bogota and EPM in Medellin; the comparison applies more fully to SEGBA since both PUB and SEGBA have entirely thermal generation and subterranean distribution networks while the Colombian municipal companies have predominantly or entirely hydroelectric generation and mainly surface distribution networks. As seen in Table 14.14, PUB's rate of return (standardized concepts) has steadily increased from 8% to more than 15%, averaging more than 11% over 1960-70 (except in 1965/66 when fuel and maintenance taxes were temporarily increased), while SEGBA's, EEEB's and EPM's rates of return have decreased over time from 15-16% to 10-11% (with significant drops in 1964-1966). SEGBA was on several occasions not allowed by the Government to increase its tariffs according to its concession, and the reductions in EEEB's and EPM's returns on assets are mainly due to political difficulties in raising tariffs and to very large increases in assets accomplished following periods of shortage. Returns average 10.4 and 9.5% over 1960-70 in EEEB and EPM respectively; the apparently high 13.9% average return of SEGBA is due to the inclusion in the revenues of indirect taxes which have accounted on average for more than 6.0% out of the 13.9%. PUB has succeeded in reducing its average price/kwh sold by US¢ 0.15 over 1960-1970 as well as EEEB, while SEGBA and EPM increased their average prices by US¢ 0.30 and 0.20 respectively; but PUB has also increased its average profit per kwh sold by US¢ 0.5 over the last decade whereas EEEB experienced a decrease of US¢ 0.2 in average profit. PUB's good performance was made possible by a substantial reduction in its average cost per kwh sold, in contrast with other companies which did not show any economies of scale despite their greatly increased operations. This is shown in the following table which also compares the structure of unit costs in the four cited utilities:

TABLE 14.15: STRUCTURE OF AVERAGE COSTS/KWH IN UTILITIES SERVING URBAN AREAS (IN %)

	1960	1962	1965	1967	1970
PUB (Singapore)					
Administration	8	10	10	9	9
Fuel	35	31	38	27	33
Other operating costs	24	26	26	25	22
Depreciation	33	33	26	39	36
Total	100	100	100	100	100 a/
Average Cost/kwh (US¢)	1.7	1.6	1.7	1.5	1.0 a/
SEGBA (Buenos Aires)					
Salaries and Wages	n.a.	34	47	44	n.a.
Fuel	n.a.	22	20	18	n.a.
Other operating costs	n.a.	27	21	19	n.a.
Depreciation	n.a.	17	12	20	n.a.
Total		100	100	100	
Average Cost/kwh (US¢)	2.5	2.5	3.0	2.6	2.3
EEEB (Bogota)					
Salaries and Wages	45	48	37	34	38
Fuel	14	7	6	3	3
Other operating costs		13	16	14	15
Depreciation (revalued)	41	32	41	49	44
Total	100	100	100	100	100
Average Cost/kwh (US¢)	0.5	0.6	0.7	0.8	0.6
EPM (Medellin)					
Salaries and Wages	48	52	54	43	45
Purchased Energy		3	-	-	-
Other operating costs	21	21	6	9	11
Depreciation (revalued)	31	24	40	48	44
Total	100	100	100	100	100
Average Cost/kwh (US¢)	0.4	0.4	0.5	0.6	0.5

a/ The average unit cost is for 1970 but the structure is that of 1969.

5.08 Though the available breakdowns are not easily comparable (it has not been possible to isolate salaries and wages exactly in PUB, as in the other companies), it can be inferred from Table 14.15 that non-fuel-and-depreciation costs have been in PUB about one-third of similar costs in SEGBA (US¢ 0.5 as compared to US¢ 1.6 on average), partly due to the fact that the latter has been suffering from seriously restrictive labor practices and a very excessive labor force, larger even now than CFE's, for instance. PUB compares favorably with EEEB and EPM only in terms of the trend in the average cost, since operating costs of the Colombian companies have been much lower than PUB's due to the great predominance of hydroelectric generation and the favorable sites available; but they have increased from 20-30% to about 50% of PUB's average cost over the last decade. The predominance of hydro generation in Colombia is also the main explanation why labor productivity in EEEB and EPM, in terms of energy sales per employee, has been substantially greater than PUB's, where it is, nevertheless, twice that in SEGBA. With regard to other financial indicators, PUB's debt/equity ratio decreased to 53/47 in 1970 as compared to 45/55 in SEGBA, and more than 60/40 in EEEB and EPM; debt service coverage (number of times operating income before depreciation cover interest and amortization) has averaged more than 2 in PUB and less than 2 in the other companies.

5.09 Transmission and distribution losses in PUB have been kept at a reasonably low level - about 7% of generation sent out - while they have increased elsewhere, averaging more than 9% in EEEB, about 15% in SEGBA and more than 20% in EPM (especially in the latter two cases including sizeable amounts of stolen energy, accounting for as much as half of the losses in EPM). The quality of PUB's electricity service has been satisfactory, without prolonged outages or unreasonable delays for making new connections (70% of Singapore's households are presently connected to PUB's network); the two Colombian companies have provided since 1963 a reliable supply but the service of new customers has been deficient in Medellin (EPM). In Buenos Aires, the power-supply situation, which was very critical in the early 1960s, has improved considerably but still suffers from serious deficiences in terms of both outages and new connections. The major apparent drawback in PUB's management has been the low availability factor of its plants (average capacity in service as % of installed capacity) which has declined markedly over the last five years (with a minimum of 75% in 1967) and averaged 84% over 1965-1970, as compared to about 92% in SEGBA and EEEB, and 98% in EPM.

5.10 Furnas has been supplying power in bulk from its large hydro-electric plants through an extended transmission network, and as such can be compared to VRA in Ghana and CHIDRAL in Colombia, although they are of course much smaller, especially the latter. Actually, Furnas compares very well not only with the two other bulk suppliers but also with most of the other companies under review. Furnas has increased its standard rate of return from 6 to 19% over its past operating years (1964-1970); the revenues considered for calculating this return have, however, included sizeable amounts of indirect taxes levied on the final sales of Furnas' clients, while VRA's and CVC's final customers do not pay such taxes. Comparison of the rates of return excluding the taxes shows that Furnas' return has increased from 8 to 13% averaging 11% over 1965-1970 while CHIDRAL's return decreased from 6% to negative over 1960-66 and averaged less than 4% over 1967-69 and 1960-69; VRA's return has remained very low since its first full year of operations (1965) but has been slowly increasing (except in 1967 when it began to operate at full capacity), averaging 2.5% over 1966-1970. Due mainly to increased depreciation allowances and responsibilities (including the take-over of relatively inefficient plants; see Chapter III), Furnas' average cost per kwh sold tripled over 1964-1970 as well as its average revenue and profit per kwh sold, reaching US¢ 0.6, 1.6 and 1.0 respectively in 1970. Chiefly because of its special power supply contract (Chapter V), VRA's average revenue/kwh sold has remained constant since 1967 at US¢ 0.4, with decreasing average costs allowing the company to earn an average profit/kwh sold which increased from US¢ 0.1 in 1967 to US¢ 0.2 in 1970. CHIDRAL in Colombia presents rather odd and disappointing records; the average cost (in real terms) per kwh sold has increased steadily up to US¢ 0.6 in 1969, while the average unit revenue has been fluctuating widely, with profits and returns decreasing over the early 1960s down to negative values and increasing afterwards to reach in 1969 their 1960 level.

5.11 Other financial indicators show that Furnas' financial situation has been satisfactory and steadily improving; the self-financing rate increased over 1964-1970 from 23 to 47% (with a minimum of 16% in 1967 due to the large amount of investments undertaken in that year), the debt/equity ratio has been decreasing from 82/18 to 56/44 with the debt service coverage averaging 2. Due to the initial equity contribution of Ghana's Government, VRA's debt/equity ratio has been satisfactory with a maximum of 56/44 in 1968; its low revenues have not allowed VRA to contribute significantly to its small investment programs after 1966, but the debt service coverage has improved slightly from 0.9 in 1967 to 1.3 in 1970. The only similar indicator available for CHIDRAL, the debt/equity ratio, has been increasing from 46/54 to 69/31 over 1960/69 with a maximum of 78/22 in 1968, a poor performance compared with all the other companies reviewed.

5.12 On the technical side, transmission losses for Furnas (5%) have been higher than in VRA's and CHIDRAL's networks (about 3%) due to the much larger size of the former's network; the availability factor of Furnas and VRA plants has been satisfactory, averaging about 91% (with a minimum of 82% in 1966 for Furnas and in 1967 for VRA). 1/ Labor productivity measured in terms of kwh sales per employee has been naturally very high in Furnas and in VRA, increasing over time and reaching more than 2,500 Mwh per employee in the late 1960s. While the organizational, financial and technical performances of CHIDRAL have been poor (very low returns, lack of adequate planning and engineering, capacity shortages), Furnas has grown rapidly into a leading entity in Brazil's power sector with important responsibilities in coordinating the sector in the South-Central region; under its tight financial constraints, VRA has been operating satisfactorily on the whole. The major drawback of Furnas has been its tariff structure with very heavy demand charges (including ratchet provisions) and comparatively high prices which could result in over-investment in capacity by the various connected utilities and in difficulties for Furnas in selling its power, as experienced in 1965.

1/ The corresponding figure recorded for CHIDRAL is 97%, but it is very doubtful whether this has any validity.

5.13 The three remaining companies - Malaysia's NEB, Mexico's CFE and Ethiopia's EELPA - are of an intermediate type between those analyzed previously; these companies are directly responsible for power supply on a nationwide basis (except for relatively small and limited concessions to other companies: PRHE in Malaysia, Centro in Mexico, and Asmara in Ethiopia), they cover all phases of electricity supply, and their power systems include hydroelectric as well as thermal and diesel plants and substantial transmission networks. The major difference between these three companies is in their sizes: CFE is the national power authority of a large semi-developed and industrialized country, with 5,400 MW installed capacity and almost 4 million customers; NEB is the national power authority of a smaller and poorer but still relatively well off country with large tin mines and a few industries, with 670 MW and about half a million customers; EELPA is by far the smallest utility under review, servicing mainly residential customers in an extremely poor country, with a capacity of almost 120 MW and barely more than 100,000 customers. The rates of return have been somewhat similar, averaging 8.5, 7.4 and 7.0% over 1960-70 for NEB, EELPA and CFE respectively; NEB's return has most of the time been over 8% (except in 1963/64 when fixed assets increased substantially with the commissioning of its first large plants) and does not show any marked increasing trend. EELPA's return increased from about 5% in 1960/64 to more than 8% after 1964 (when the first Bank loan was made) and has been increasing since, reaching almost 10% in 1970. After a series of very low or negative returns in the 1950s when it was a small company operating primarily as a bulk supplier, CFE raised its return to about 7% in 1962; due to its very large subsequent investment programs, the return dropped to about 4-5% in the middle 1960s but recovered gradually afterwards (partly due to the Bank's action for increasing the revenues) and reached almost 10% in 1968 and 8.5% in 1970.

5.14 As in the case of PUB, NEB has been able to earn high returns with average prices per kwh sold steadily decreasing over time from US¢ 3.2 in 1960 to US¢ 2.6 in 1970, which is reasonable; this was due to decreasing unit cost per kwh sold (US¢ 2.5 in 1960 to US¢ 1.7 in 1970), though the share of thermal generation has increased substantially in NEB's system. In Ethiopia, the average revenue and cost per kwh sold have been decreasing as well, due to increasing importance of hydroelectric energy but remained very high in 1970 - US¢ 3.7 and 2.2 respectively - the highest among the 10 utilities covered in the review. Up to 1960 CFE had been keeping its average revenues and costs per kwh sold at low levels comparable to those in Colombia, in particular by means of inadequate depreciation allowances; as a result of its increased responsibilities in administration of the power sector and in distribution operations, costs and revenues increased slowly up to about US¢ 1.0 1/ and 1.4/kwh sold respectively in the mid 1960s, which were still very reasonable levels resulting from CFE's continuous attention and obligation to keep tariffs at the lowest possible levels; when CFE absorbed in 1967 a large number of its affiliates operating mainly in distribution, its average cost jumped to its present level of about US¢ 1.2 1/, and its average revenue to US¢ 1.8, the lowest levels among these three companies.

1/ Unit cost/kwh sold as calculated in this report after corrections for depreciation.

5.15 Other financial indicators reflect NEB's sound financial position; the debt/equity ratio has decreased over the last decade from about 70/30 to 55/45, the self-financing rate has increased from about one-third to more than one-half and the debt service coverage has remained well above 2 (except in 1966 when it dropped to 1.8 when bank overdraft short-term debts incurred in 1964-65 were reimbursed). A similar trend has been experienced with EELPA, although its debt/equity ratio has increased from 0/100 to 43/57. In CFE, the debt/equity ratio was kept at satisfactory levels, reaching 53/47 in 1970; the Government constantly preferred to make equity contributions rather than let CFE increase its tariffs, so that, as a result of the very large investment programs undertaken by CFE after 1958, both the self-financing ratio and the debt service coverage remained at very low levels, reaching negative and smaller than unity values in 1965 with the debt servicing of large supplier credits and short-term debts incurred in the early 1960s. The same situation has recurred in 1970 with the debt servicing of the large medium-term loans incurred by CFE since 1965 from commercial banks (see Chapter VII).

5.16 Despite its risky financial management,CFE's operations have been generally satisfactory; transmission and distribution losses increased slowly before 1967 and reached more than 10% of energy sent out in the late 1960s due to the absorption of numerous distribution networks. Productivity of labor has been growing slowly, 4% per annum on average, reaching in 1970 its 1966 level of 1,090 Mwh per employee, which is quite satisfactory for a company of this type serving a huge territory with scattered population and supplying power to a rapidly increasing proportion of this population (Chapter VII).

On NEB's system, transmission and distribution losses have been gradually falling on its expanding network and represented less than 10% of energy sent out in 1970; a minor drawback of NEB has been its relatively low ratios of sales and consumers per employee, as a result of the large number of isolated localities served by the Board and Government pressure to increase employment; but the labor productivity has been increasing rapidly, at more than 8% per annum on average over 1960-70, reaching about 230 Mwh per employee. It has been growing rapidly in EELPA as well, reaching the still fairly low level of 115 Mwh per employee, but EELPA's transmission losses have remained somewhat high (about 13%).

VI. Bank Objectives and Loan Agreement Covenants

6.01 Apart from the direct technical objectives of the Bank loans (size, schedules and costs of power facilities intended to meet certain forecast demands), the achievement of which has been discussed in the previous sections of this Chapter, the Bank has sought to achieve within the utilities or the related power sectors a certain number of objectives of a financial and institutional type which were most of the time expressed in or by the Loan Agreements in the form of covenants and side letters attached to the Loan Agreements.

6.02 As can be seen from Appendix Table 14.6 which presents in a summarized form most of the covenants and side letters connected with the 29 loans which have been fully or nearly fully disbursed, the Bank's covenants and side letters have generally been intended to set conditions on the utilities or on the Governments to assure (a) sound financial management and development and

(b) sound organization and operations in the utility and/or the power sector. The covenants of a financial type have taken several exclusive or complementary forms, e.g., set tariffs at levels sufficient to obtain a minimum financial rate of return or a minimum self-financing ratio, income or debt/equity tests on the incurrence of long-term debt without Bank approval, maximum levels put on the short-term debt, audit of income statements by external auditors. The covenants of an institutional and management type have generally required either that the utility should take specific actions on points relating to its internal management and operations or that the Government should respect concessions, enforce certain legislation and regulations specific to the power sector, promote reorganization and/or coordination within the power sector, or sometimes obtain the Bank's agreement or prior approval to the appointment of the utilities' top management and senior officers. Finally, some covenants or side letters have dealt with some specific aspects of the loan itself (retroactive financing, local procurement, procedures for international competitive bidding).

Tariff and Financial Covenants

6.03 All the power utilities (except EPM and CVC/CHIDRAL in Colombia) when borrowing from the Bank agreed in connection with at least one Loan Agreement, not necessarily the first one, to assure the Bank that power tariffs would be maintained at an "adequate" level, the adequacy concept varying with the individual companies and countries and the changing preoccupations of the Bank and evolving over the years to be more specific and efficient. The important trend in the Bank's approach has been from fixing, often rather vaguely, in the 1950s and early 1960s the share of construction expenditures to be covered by the utility out of its earned surplus (the self-financing rate) to principle reliance after the early 1960s on some agreed minimum rate of return on the net fixed assets in service. In the countries subject to severe inflation (Argentina, Brazil, Colombia), the Bank has also requested the utility or the Government to introduce mechanisms or regulations allowing the utilities to revalue their assets to current prices.

6.04 Among the 10 utilities under review, only SEGBA and PUB have been required since their first Bank Loan Agreements (in 1962 and 1963 respectively) to earn a minimum rate of return on their assets; the minimum rate was 8% for both. 1/ Three other companies, EPM, EEEB and EELPA were required in the first Bank Loan Agreements (in 1959, 1960 and 1964 respectively) to earn revenues such that current surplus after debt service would contribute a minimum proportion to the costs of their system expansion, this proportion being set at 30% for EPM and 40% for EEEB and EELPA; only EEEB and EELPA were required in further Loan Agreements (in 1968 and 1969 respectively) to earn a minimum rate of return, specifically 8% for EEEB and 7% for EELPA. Other companies, Furnas, CVC/CHIDRAL, VRA, NEB and CFE were not requested formally to respect any type of tariff covenants in their first Loan Agreements dated respectively 1958, 1950, 1962, 1958 and 1949; in subsequent Loan Agreements only Furnas (in 1965), NEB (in 1963) and CFE (in 1958) agreed to earn a minimum rate of return on their assets, set at 10, 8 and 9% respectively (actually CFE was requested in 1958 to earn a 9% return on its large systems only, see Chapter VII). In 1962, CFE was required to cover from its own funds, including the

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1/ Actually the Argentine Government was only required to enforce SEGBA's concession which allows SEGBA to earn a minimum 8% return on its revalued assets.

proceeds of the Power Consumption Tax, one-third of its construction program on a running four-year basis, and in 1965 the Bank reverted to a minimum rate of return covenant of 8%. In the cases of SEGBA and Furnas the Bank also obtained, in connection with the first Loan Agreements, commitments from the respective Governments to respect concessions or enforce regulations allowing the utilities to revalue their assets to current prices; in Colombia the Junta de Tarifas established in 1968 under Bank auspices has based its tariff increase approvals on the principle that utilities' assets should preferably be adequately revalued for tariff calculations.

6.05 Other major financial covenants have put limitations on the utilities' incurrence of long-term debt without Bank approval. Most of the time, these limitations took the form of a test to be applied on the maximum of future debt service resulting from the debt to be incurred; according to these tests, the debt service coverage 1/ was to be at least a number ranging from 1.3 (CVC/CHIDRAL and EEEB in 1960) to 1.4 (EELPA in 1964 and CFE in 1965), and 1.5 (CFE in 1949 up to 1965, NEB in 1958 , VRA in 1962, PUB in 1963). In the case of SEGBA, the test agreed upon in 1962 specified that net income after depreciation was to cover maximum future interest payments 1.75 times, and that the debt/equity ratio was not to exceed 40/60; in the case of Furnas, CVC/CHIDRAL and EPM limitations were put also on the debt/equity ratios which were agreed not to exceed 50/50 (CVC/CHIDRAL, 1955), 60/40 (EPM, 1959) or 67/33 (Furnas, 1965). A standard covenant requiring the utilities to have their financial statements audited by independent external auditors has generally been inserted in the first Bank Loan Agreements with the utilities,

1/ Number of times operating income before depreciation covers interest and amortization.

except for Furnas, CFE and CVC (second, fourth and fourth Loan Agreements respectively).

6.06 Most of the companies reviewed here have respected Bank financial covenants in most years. With regard to the financial rate of return, self-financing ratio and long-term debt test covenants, Table 14.16 shows the years when the companies have not conformed with Bank covenants. The figures in brackets alongside the dates or beneath them represent the values assumed in those years by the indicators to which the covenants referred. With regard to the test for incurrence of long-term debt it should be noted that a figure below the test level need not necessarily indicate a departure from the covenant, as implied by the table. In the first place the debt-service coverage may have fallen below the test level without new long-term debt actually having been incurred; in the second place, even if such debt was incurred, prior permission may have been obtained from the Bank, as required by the covenant. Actually it is almost certain that SEGBA, VRA, EPM and CVC/CHIDRAL did obtain approval when incurring new long-term debts, if any, in the years listed. However in some instances, as in 1959, CFE incurred long-term debts (small supplier credits) despite the Bank's disapproval or without the Bank's knowledge; also Centro incurred in 1969 large short-term debts without Bank approval, which was required as a result of a unity current ratio test covenant introduced in 1965 and not met by Centro.

6.07 Tariff covenants, in the form either of self-financing ratios or of financial rates of return, were not met in several instances. CFE was able to finance its 1961-64 investment program from self-generated funds only to the extent of 21% as against 33% required by the 1962 Loan Agreement; this shortfall was due to the inadequacy of its tariffs (including the power tax) which were finally raised to a satisfactory level only in early 1966 as a result of strong Bank pressure (Chapter VII). EELPA fell short of the required 40% self-financing ratio by a significant amount over 1965-67, but complied with the covenant afterwards. In Colombia, EEEB and EPM fell short of the required 40% self-financing ratios in the first half of the 1960s -- in the case of EPM, by a small amount only and for a brief period, but in the case of EEEB much more seriously and frequently; this resulted from the reluctance of the companies to apply for and of the Government to approve tariff increases in a period of rapid inflation (Chapters X and XI).

6.08 The rate of return covenants were not complied with in six important instances. NEB in 1967 fell short of its 8% required rate of return only by a very small amount and temporarily (as a result of a large increase in its assets). In Singapore, due to a drastic increase in 1965-66 in fuel and property taxes, which the Government subsequently reduced at the Bank insistence, PUB's rate of return fell short by 2 and 1% respectively of the required 8% rate of return. In Argentina, in 1964-65, 1967 and 1970 the Government did not allow SEGBA to apply its concession; in 1964-65 it turned down SEGBA's request for rate increases, and in recent years the Government granted only part of the rate increases required to recover out of 1968 and 1971 revenues the shortfalls incurred in 1967 or 1970. In 1966, as one of the conditions for further Bank lending, the government reversed its stand of 1964-65, and in 1968 it compensated for the 1967 shortfall through appropriations as an extraordinary revenue; the 1970 problem is still unsolved (Chapter II). For the sake of accuracy, it is worth mentioning that Furnas fell slightly short of its tariff covenant (10% return before taxes) to a very small extent in 1969. Also CFE had agreed in a side letter to the 1958 Loan Agreement to earn a 9% return on its own large systems, mainly for tariff homogeneity purposes; data available for 1959 indicate that this was complied with only in 2 of its 6 systems, and it is probable that this situation continued until1962 when nationwide tariffs were introduced in Mexico.

6.09 As shown in Table 14.16, the 1960-70 average financial returns have varied to a large extent among the 10 companies under review. Except for the special case of VRA (Chapter V) which is only expected to earn an 8% return after 1974, the lowest average financial return has been earned by CVC/CHIDRAL while the highest returns were earned by EEEB and PUB's Electricity Department. It appears that the inclusion of tariff covenants in the Loan Agreements and their somewhat continuous respect have been an important means of obtaining from the utilities and/or the Government the establishment of financially adequate tariffs. The case of CVC/CHIDRAL which was most of the time required to comply with very vague or empty covenants may demonstrate a contrario the effect of the tariff covenants on the overall financial performancesof the companies. However, as shown in several instances (SEGBA, EEEB) and developed at length in Chapter XVI, the mere existence and fulfillment of tariff covenants does not ensure by itself a sound and efficient management of the utilities nor an optimal allocation of the costs to the various types of consumers' demands (tariff structure), essentially because the tariff covenants have not dealt with the important cost aspects of the utilities but only with their overall average revenues.

6.10 The arrangements made by the companies to have their accounts regularly audited by external auditors have been satisfactory most of the time. Arrangements made by SEGBA, Furnas, VRA and NEB appear to have been quite effective. This has been true also, but to a lesser extent, for EELPA where there were however rather long time lags in preparing past financial statements; the covenant of the 1969 Loan Agreement that audit reports be sent to the Bank within 5 months of the close of each year has been met in 1970. PUB complied with the 1963 external auditing covenant with a 3-year delay, but since 1966 accounting procedures have improved and worked well. CFE began to have its accounts regularly audited by external auditors as of 1963 as required by the 1962 Loan Agreement; auditing however has not been very satisfactory nor efficient since debt service projections based on the audits have often been underestimated (Chapter VII). In view of the still rather inadequate state of financial records, it would appear also that external auditing arrangements made by EEEB and EPM have not been entirely satisfactory. For CVC/CHIDRAL they appear to have been quite inadequate.

Management and Institutional Covenants

6.11 As shown in Appendix Table 14.6, a large number of covenants and side letters were attached to the Loan Agreements aimed at the achievement of specific actions and improvements in the internal management and organization of the companies or in the operations and policies of the power sectors as a whole. These legal instruments generally dealt with three aspects of the institutional development of the power companies:

(a) improvement of the construction, technical and planning operations of the companies (SEGBA, CFE, EEEB, EPM, CVC/CHIDRAL, PUB), most of the time to be achieved with the assistance of consultants to be engaged for this purpose or by implementing the recommendations of consultants' reports already available;

(b) review, reorganization and/or improvements of management procedures and of some departments of the companies, in particular of the financial departments and procedures and of the accounting systems (EEEB, EPM, VRA, CFE, PUB); in some instances, review and improvement of the depreciation policies and tariff structures were required (SEGBA, CVC/CHIDRAL, CFE, PUB), and in other instances the reorganization of certain departments and of personnel policies (SEGBA, VRA, PUB). Consultants were not necessarily recommended for implementing these tasks; and

(c) at the sector level, the Bank's recommendations most of the time have called for the coordination of planning and of operations (load dispatch centers, inter-connection) of the various companies within a power sector (Argentina, Brazil, Colombia, Ghana, Mexico), and sometimes for a coordinated expansion of distribution networks in line with that of the generating systems (Argentina, Brazil, Colombia).

6.12 The recommendations and covenants of the first type, relating closely to the implementation of the projects themselves, were generally respected without major difficulties and delays. In SEGBA, consulting engineers were retained or engaged in due time to review and supervise the plant construction and the system expansion planning, with the result that by 1969 SEGBA's staff was capable of carrying out future projects with minimum assistance from consultants. In Mexico, the issues raised in the 1950s concerning design and coordination of all investments in generation throughout the country were partly solved in 1960 by the concentration on CFE of responsibility for planning and providing all new generating capacity and by the engagement of an International Board of Consultants recommended by the Bank to review the design and construction of all major hydro projects; several consulting firms were also engaged to undertake similar reviews for the thermal plants, as requested in 1962; training manuals and programs for the operating staff of generating plants were initiated in the early 1960s. Since 1963 CFE has carried acceptance tests of its new generating units, as requested in 1962, and it has also retained the services of general consultants for annual reviews of its investment programs; but improvements are still needed, in particular in the control of construction costs which have invariably overrun the estimates. Due to the Government's reluctance to carry it out, the frequency unification program worked out in the mid-1960s by consultants has remained pending full implementation. In PUB, engagement of consultants to undertake the study of the basic distribution development program and implementation of the resulting recommended program followed closely the 1967 Loan Agreement which called for these steps. In Colombia, provisions of the Loan Agreements calling for the use of technical consultants have apparently been fulfilled satisfactorily.

6.13 Bank Loan Agreement covenants dealing with internal managerial and organizational aspects of the companies were in several instances fulfilled with delays and difficulties. In SEGBA, the 1968 side letter calling for use of a minimum 3% annual depreciation rate for fixed assets has been fulfilled since; the huge labor problem of SEGBA has begun to be solved, and since 1968 the number of employees has been reduced by more than the 1,000 man reduction during 1968 which was verbally agreed at the time. In CFE's financial departments which had long needed coordination and reforms, consulting firms were engaged in 1959, as recommended by the Bank in 1958, to review and reorganize the organization, procedures, controls and financial and budgetary planning; these recommendations began to be implemented in 1962 and have led to considerable improvements, although further measures are still needed. The depreciation policy of CFE was considerably improved in 1962 (Chapter VII), and CFE has since charged acceptable although still rather low depreciation rates; since 1965, CFE has made annual reviews of a detailed study of its property account originally carried out in compliance with a 1965 covenant. The consultant review of VRA's operations, organization, accounting system and staffing policies requested by the Bank in 1968 was made in 1970, and recommendations are being examined. In PUB, the reorganization of the accounting department called for in 1963 was implemented with a delay of several years but yielded positive results, with the accounts presented since 1966 on a commercial basis and progressively refined and with the establishment in 1967 of efficient budget control and management reporting; consultants' recommendations on the simplifcation of the electricity tariff structure are being implemented gradually, with the completion expected by 1972, as required by the 1969 Loan Agreement. The management consultants hired to adivse on PUB's organization and measures to improve its internal efficiency appear to have had beneficial effect, as indicated by the improvements in the utility's performance but they did not succeed in bringing any solution to the "top management" problem because it was mainly a matter of personalities. In the case of the Colombian companies covenants were agreed regarding company statutes and Board composition (EEEB and EPM) and these appear to have been adhered to despite pressures for change (see Chapter XV); commitments for separate accounting for the Electricity department of EPM and for reorganization of financial work in EEEB were also fulfilled though with some delay in the case of the latter; in CVC the covenants seem to have been less fully observed, and, in particular, the power operations of CVC and CHIDRAL have not been amalgamated as called for in 1963 (Chapter XII).

6.14 Important commitments were made in Loan Agreements with companies in five countries regarding measures of sector policy. In Argentina, coordinated planning of generation and distribution expansion in the whole Buenoes Aires area, as called for in the 1962 Loan Agreement, has been gradually accomplished by improved cooperation among the three entities involved. A central load dispatch center for the whole area has been operated by SEGBA since early in 1968. In Brazil, as required under agreements reached in connection with the 1965 loan to Furnas, the Government has taken effective action to ensure that the companies responsible for distribution would expand their networks, which were then at the saturation point, commensurately with the growth of transmission and generation capacity. This has been aided by several external loans as well as by the 1964 decrees permitting more adequate tariffs, which had been promoted by the Bank. A frequency unification program in the South Central Region has also been underway. Achievements were also important with respect to coordination of the planning and operations of electric power as requested in 1962 and 1965; the priority list of power development sites provided in the UNDP study made under the Bank's supervision was followed by the main utilities in the South-Central region and since 1968 Furnas has been chairing the committee for coordinating expansion of the power systems and the interconnection committee (recommended by the Bank since 1958), the latter resulting in the establishment of the inter-utility load dispatch centers with the first one to be completed by 1972. In Ghana, the ECG was established according the 1962 Loan Agreement, but with some delay (1967 as against 1965).

6.15 The last decade has seen the progressive building and consolidation of CFE into the leading electrical utility and the responsible authority in the Mexican power sector, due principally to the Government's decision in 1960 to nationalize the whole sector and to give CFE full responsibility for planning and construction of all new generating capacity. The Bank's Loan Agreement covenants which had been calling since 1958 for coordination of planning and operations of electric utilities in Mexico lost part of their relevance after 1960 but still continued to play a useful role, in particular with respect to the coordination of operations between CFE and its affiliates and Centro. A covenant in the 1968 Loan Agreement called for the establishment in each of the 10 major systems of load dispatch centers, resulting in the creation of four such centers up to now. The Bank has also continued to ask for studies about the advisability of frequency unification and interconnection between the major systems; interconnection between the major Occidental and Oriental systems was made in 1967 but was not extended to the most important Central system because the frequency conversion in the latter has not been carried out although repeatedly requested since 1965 in three Loan Agreements. Institutional prerequisites for such conversion, however, have been fulfilled and the implementation of the first phase of the frequency conversion program is expected for 1972; CFE is also planning for the complete interconnection of all the major and smaller systems during 1971-74. Finally, the Bank also called in 1965 for the coordination of the Power sector with respect to financial operations; in 1969 the Government gave CFE full responsibility for the financial management of the sector, through the absorption of all other companies except Centro and through control of the latter.

6.16 In Colombia the main sectoral developments with which the Bank has been associated are barely reflected in the covenants for loans to the three main companies, partly because the main steps were accomplished through other means, including prolonged refusal of new lending and separate agreements with the Government on economic policy. However the 1968 Loan Agreement with EEEB did record the company's commitment to the Interconnection Company, linking the main power markets of the country, and also the Government's commitment to take action to establish a National Public Utilities Tariff Board. While the former progressed rapidly at that time, the Government was slow in taking action to establish and make effective the Tariff Board but the Board has now been operating reasonably effectively for two years and is beginning to introduce a sounder tariff regime for both water and power utilities throughout the country. The 1968 Loan Agreement with EEEB is also the first legal expression in connection with electric power of another important principle which was introduced into Colombian utility tariff making largely at the instance of the Bank -- namely revaluation of assets.